The Value of Frequency Keeping and Governor Response to New Zealand

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***Abstract*— This paper presents analysis on the benefit of Governor Response service by generators and of the Frequency Keeping ancillary service. The benefit is the value of the services to the System Operator and ultimately New Zealand by maintaining secure operation of the grid. Governor Response and Frequency Keeping manage normal variations in demand and intermittent generation, to keep the frequency in the normal band. This ensures secure operation of the grid, and thereby minimises frequency deviations when a contingent event occurs. Ultimately this reduces the likelihood of black-outs, indicating the importance of these services. This is of interest to the GREEN Grid project, which is investigating ways of managing increasing amounts of intermittent renewable generation. Knowing the benefits of these services, and how intermittent generation changes that value, enables GREEN Grid to assess the cost of increased intermittent renewable generation, how those costs should best be recovered, and to assess new ancillary service markets for them. These markets may include demand response.**

An analysis of the value of Governor Response and Frequency Keeping is considered from the perspective of avoiding lost load due to sub-optimal management of contingent events. Value is also considered from the perspective of how normal frequency is managed.

Keywords-component; Ancillary Services; Power System Stabiliy; Frequency Quality; Event Contingency; Value of Lost Load

I. INTRODUCTION

Intermittent Renewable Generation (IRG) detrimentally effects frequency management, which has the potential to increase the cost of services used to control frequency. It is therefore important to value the current services so that the most efficient choices in frequency management are made. The value of these services is considered in terms of frequency quality and the susceptibility to trigger load shedding for a contingent event. A dollar value is placed through estimating the cost of lost load as a consequence of insufficient frequency management.

II. BACKGROUND

The stability and reliability of the electricity grid is dependent on efficient design and management of the power system. Frequency management is critical to operation, as many system components have operating ranges within a narrow frequency band. Any sufficiently large frequency deviation will isolate important system components, generators, and consequently disconnect load, either as a result of the Automatic Under Frequency Load Shedding (AUFLS) relays, or because the whole system has collapsed: Blackout. Therefore it is necessary to limit frequency deviations to avoid the severe economic and social impacts of load shedding on the country.

Grid frequency is managed by multiple control systems. The governor of each generating unit is of primary importance, as it has the ability to regulate real power transfers, and stop frequency deviations. Frequency Keeping (FK), an ancillary service procured by the System Operator, is used to regulate grid frequency as well as other functions, such as controlling time error.

Frequency management in New Zealand has seen recent developments. Firstly with the change from a Single Frequency Keeping (SFK) system to a Multiple Frequency Keeping (MFK) system, allowing more than one generator in each island to provide the FK service. That is from a single isochronous generator in each island (SFK) to a system which operates similarly to Automatic Generation Control in practice (MFK). MFK was commissioned in the North Island (NI) on the 1st July 2013 and on the 4th August 2014 for the South Island (SI). Secondly the new Pole 3 link allows the new Frequency Keeping Controller (FKC) to minimise the frequency difference between the two islands. FKC Trials started in October 2014, Fig. 1.

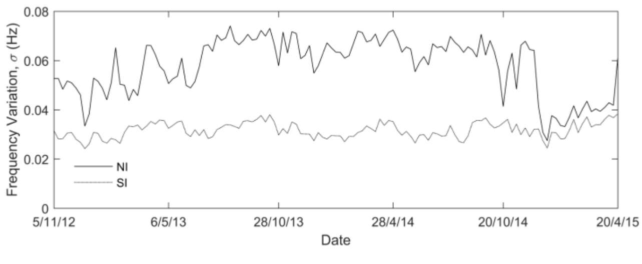

Figure 1: Weekly frequency quality from November 2012 to April 2015. NI is North Island, SI is South Island. Frequency Variation is defined as the standard deviation of the grid frequency.

Thank you to the Sponsors of the GREEN Grid project: especially to the Ministry of Business, Innovation, and Employment; and to Transpower.

III. Power System Model

To assess frequency quality and grid susceptibility to load shedding, two models of the New Zealand frequency control system are created. Frequency quality is analysed from a model implemented in Simulink and shown in Fig. 2, whereas grid susceptibility is assessed from an analytical model of the power system.

The Simulink model consists of four main components: the NI and SI power systems, the FKC unit coupling the two islands, and the MFK controller sharing the FK service between the two islands. The model consists of one main input, electrical power demand, and one output, frequency, for each island. The electrical power demand is the difference between the load and the generation dispatch. Since wind generation is considered a negative load, the difference between actual wind generation and wind generation dispatch is factored into electric power demand. The relationship between these quantities is shown in the following equation for the NI:

$$P_{E,NI} = Load_{NI} - Generation\ Dispatch_{NI} - Wind\ Generation_{NI} + Wind\ Generation\ Dispatch_{NI}$$

The analytical model determines the frequency response to a step change in electrical power demand, ΔP_E, given an initial frequency, f_0. The model represents the power grid as a single equivalent generator and is defined by its s-domain equation as:

$$F(s) = \frac{2Hf_0(\tau s + 1) - R\tau f_0}{(2Hs + D)(\tau s + 1) + R} - \frac{\tau s + 1}{(2Hs + D)(\tau s + 1) + R}\frac{\Delta P_E}{s}$$

where H is the total grid inertia of both islands, D is the load-dampening constant, τ is the governor time constant, and R is the droop.

The single equivalent generator model is a valid model, since the electrical frequency at the terminals of each generator are similar, due to each generator being synchronized to each other, it is possible to model the total inertia as a single component, H. Therefore the electrical frequency is dependent on the total balance in mechanical power supplied through the turbines and the electrical power drawn from generators. There are three sources of electrical power: the electrical power demand, the demand that is dependent on the frequency (load-dampening constant, D), and the contribution through FKC.

The mechanical power supplied is controlled through the governor system, which is modeled as a first order transfer function defined by the governor time constant, τ, which encompasses the governor controller, governor, and turbine. The mechanical power is regulated through a frequency feedback, with a droop, R. The combination of the droop and the governor system is referred to as Governor Response.

Inertia, droop, and load-dampening constant are dependent upon the state of the grid and therefore vary with time. These parameters are estimated from historical conditions and individual generator parameters: common values are shown in Table 1. The governor time constant is assumed constant, and is estimated to be 80s. Inertia, droop, and load-dampening constant are further explained:

- Inertia is estimated from the summation of individual inertias of generators synchronized to the grid. The distribution of inertia is shown in Fig. 3. This process assessed SCADA information from Transpower and checked the

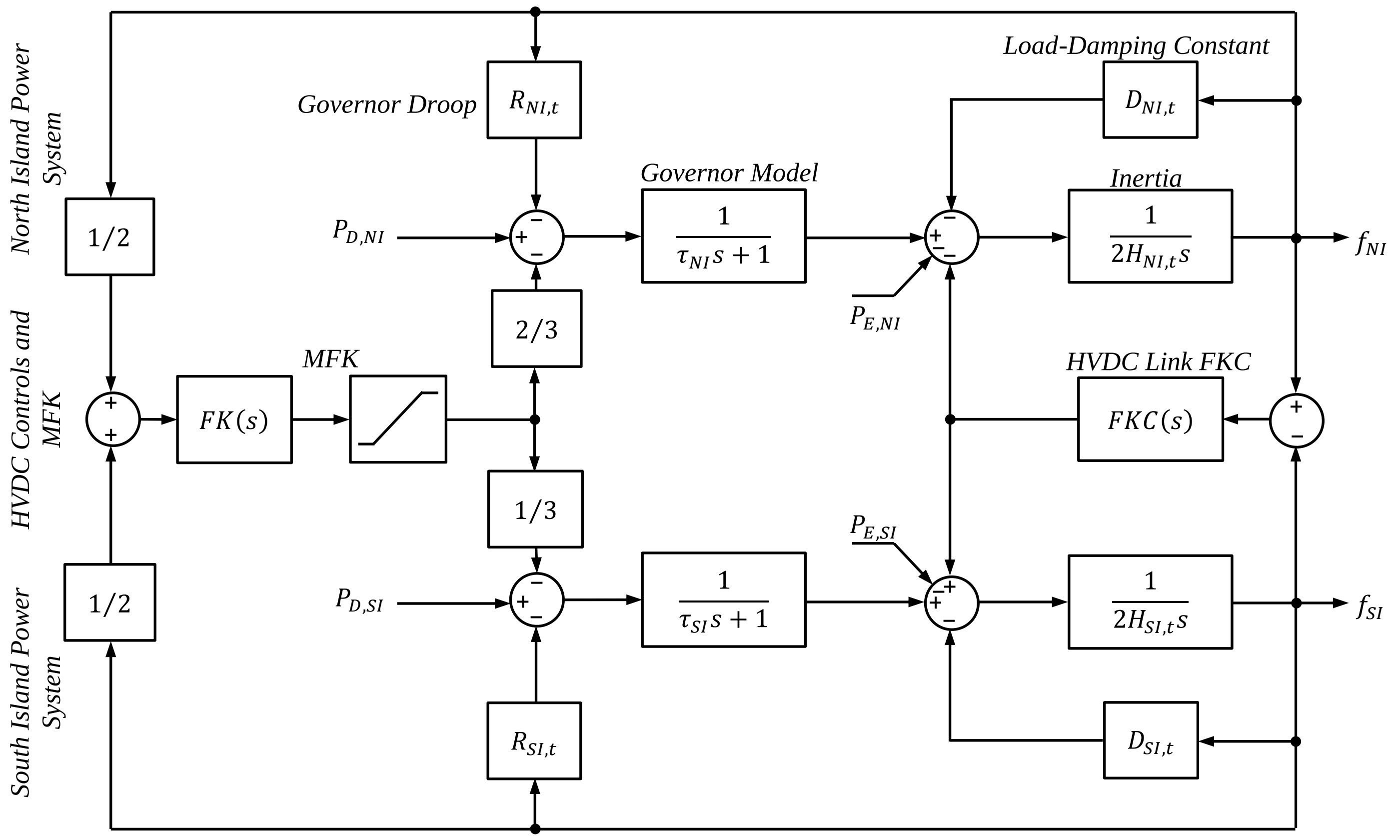

Figure 2: Control block diagram of the New Zealand power system.

times the generators were synchronized to the grid. The individual generator inertia constants are published in a Transpower report [2]

- Droop is estimated from the summation of individual droops of generators that are likely to provide droop within the normal frequency range at that point in time. The distribution of droop is shown in Fig. 4.
- The load-dampening constant, being dependent on how much demand is present, is estimated as having a value of 80 % of the demand for every 50 Hz [1]. E.g. when the grid has a demand of 3000 MW then the load-dampening constant has a value of 48 MW / Hz. The distribution of the demand is shown in Fig. 5.

The performance of the Simulink model is validated against the actual grid frequency in Fig. 6. The simulated frequency does not absolutely match the grid frequency. This is because it is difficult to model non-linear effects, the difference in Governor Time Constant between generators, and the dispatch process for each generator is difficult to model, as there is no consistent dispatch time after the instruction has been sent. However the model is accurate in the distribution of grid frequency, and the distribution of change of grid frequency. The performance of the simulated FKC controller is comparable to the actual FKC controller as evidenced by how well the modelled NI and SI frequencies follow each other.

TABLE I. STATISTICS OF POWER SYSTEM PARAMETERS

	Power System Parameters		
	***Inertia*, H(s)**	***Droop*, R**	***Damping*, D**
	North Island		
Mean	4.99	8.15	0.77
Standard Deviation	0.74	2.41	0.16
Minimum	3.08	2.89	0.43
Maximum	6.95	14.41	1.19
	South Island		
Mean	3.06	20.17	0.44
Standard Deviation	0.44	3.66	0.05
Minimum	1.65	7.29	0.26
Maximum	3.94	27.92	0.57
	New Zealand		
Mean	8.05	28.32	1.21
Standard Deviation	0.89	5.70	0.21
Minimum	5.74	12.07	0.73
Maximum	10.31	41.38	1.75

All values have a power base of 3000 MVA, and a frequency base of 50 Hz.

IV. IMPACT OF WIND GENERATION

Intermittent Renewable Generation, particularly wind power in New Zealand, affects the ability of the grid to manage frequency. These issues include the reduction of system inertia, the reduction of system droop, and the increased variability in power output.

Inertia is critical to frequency management when recovering from contingent events, because the rate at which the frequency falls is proportional to the inertia. The more inertia present the slower the frequency falls, and therefore more time is available to rectify the power imbalance before the frequency reaches 47.8 Hz (the first AUFLS block trip frequency). Intermittent renewable generation generally does not contribute to system inertia because wind turbines decouple the link between the grid frequency and the turbine speed, but can provide synthetic inertia through control

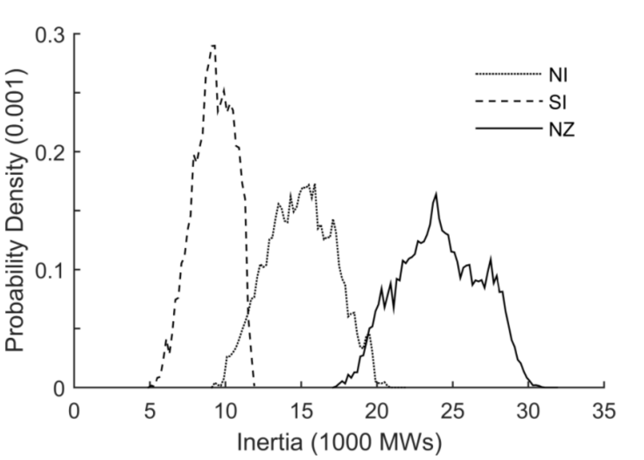

Figure 3: Probability distribution of total grid inertia derived from the inertia time series over the 2014 year.

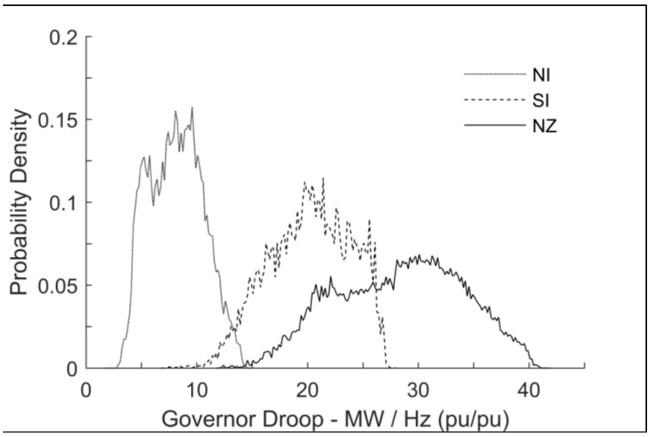

Figure 4: Probability distribution of total grid droop derived from the droop time series over the 2014 year.

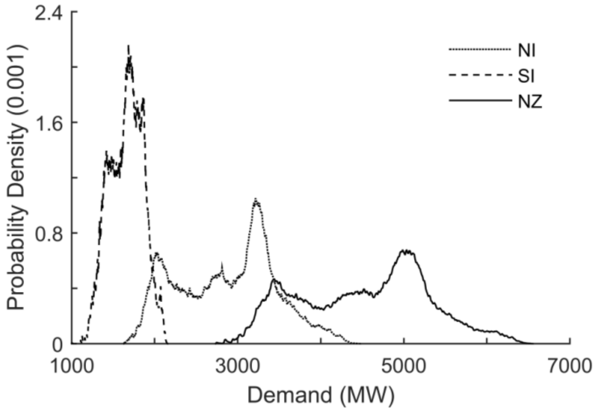

Figure 5: Probability distribution of total grid demand derived from the demand time series over the 2014 year.

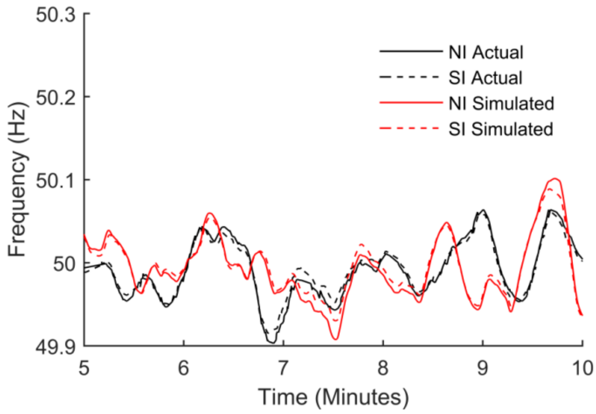

Figure 6: The simulation of grid frequency for the New Zealand power system. The results are compared against the actual measured grid frequency for the 28th April 2015 at 1:05 AM.

mechanisms if implemented. However more importantly, wind generation replaces generation that does have inertia. This is shown in Fig. 7, where currently every 1 MW of wind power generation reduces grid inertia by about 4 MWs. This is only with weak correlation, because inertia, while dependent on wind, is largely dependent on demand determining how many generators are synchronized to the grid.

Droop is important for managing both contingent events and normal frequency. Larger droop increases the response of generators to frequency deviations, therefore giving a better chance of staying above 47.8 Hz during a contingent event, and determines how closely the frequency is kept to 50 Hz in normal frequency conditions. Wind generation does not generally contribute to droop because wind farms optimize power output for a given wind resource and therefore cannot increase power output to regulate the power balance. Fig. 8 shows that every 1 MW of wind generation reduces droop by around 0.3 MW / Hz, and is not highly correlated because demand has greater influence on how many generators are providing droop.

The impact of wind generation on droop is minor, due to large amounts of Hydro generation in New Zealand. Also wind generation is likely to replace thermal generation, which is not counted in providing droop in this analysis. Hence there is no net change in droop as wind penetration is increased. Thermal generation does not provide droop because their deadband of ±0.2 Hz means they rarely respond.

Wind generation, being dependent on the availability of wind resources, is effectively self-dispatched. The difference between the actual wind power generated and the anticipated generation (virtual dispatch) becomes a source of power imbalance. More wind generation consequently increases the amount of resources required to manage this imbalance. For every 100 MW of wind generation, variability increases by about 1 to 2 MW, Fig. 9.

The second type of wind generation variability is how quickly the power output changes. The larger and faster the change in power output the larger the difficultly in managing the resultant frequency deviation. The probability of these changes is shown in Fig. 10, for changes over 5 seconds and for changes over 300s, and is compared to the changes in load. Currently changes with total wind generation are significantly less than changes in total load, but more importantly these are all less than events caused by generation tripping, where the South Island is currently managed to handle an instantaneous trip of a 120 MW Manapouri unit.

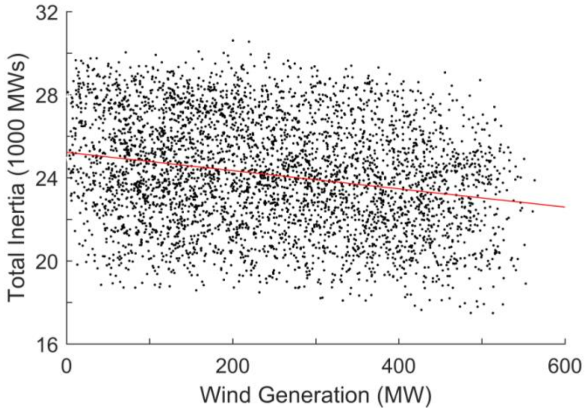

Figure 7: The dependence between total grid inertia for New Zealand and the total wind power generation for New Zealand, across the 2014 year. Each point is a two hour average. The red line is a line of best fit. The gradient is -4.39 MWs / MW, y-intercept is 25224 MWs.

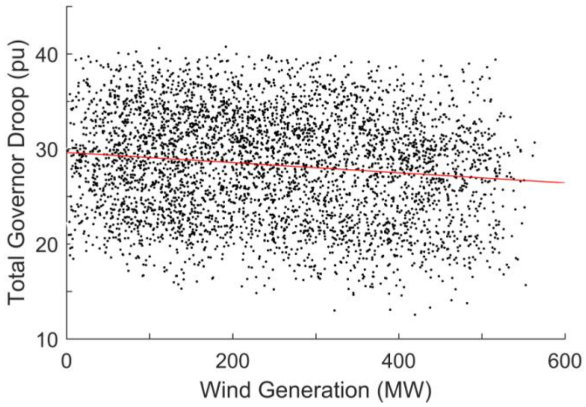

Figure 8: The dependence between total grid droop for New Zealand and the total wind power generation for New Zealand, across the 2014 year. Each point is a two hour average. The red line is a line of best fit. The gradient is -0.321 MW / Hz / MW, y-intercept is 1777 MW / Hz. Governor Droop is in a base of 60 MW / Hz.

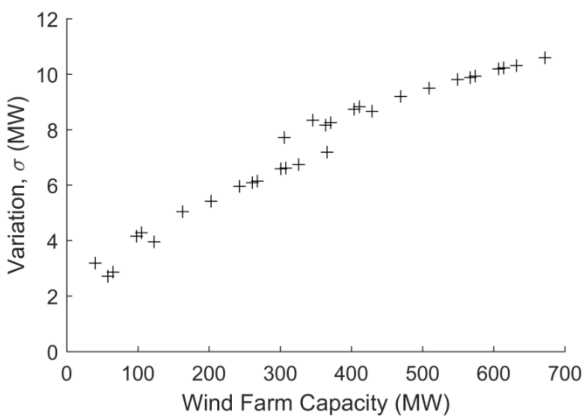

Figure 9: Variation in power output of New Zealand wind farm combinations. E.g. one point is the variation from Te Uku and White Hill. The Variation is defined as the standard deviation of the difference between the power output and the wind farm dispatch.

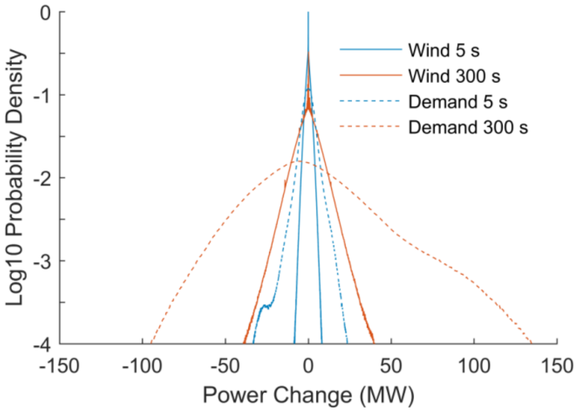

Figure 10: Probability distribution of demand and wind power variation. The Power Change is defined as the difference in power between two points in time separated by the specific time. E.g. blue line distributions are for a time difference of 5 seconds.

V. The Value from Avoiding Lost Load and Frequency Quality

To assess the value of the different contributions to frequency management, simulations of the power system are run with perturbations in the system parameters. Performance of each configuration is assessed in terms of frequency quality, event management, and the estimated cost of load lost.

The grid is managed to handle a range of imbalances between power supplied by turbines and power drawn by loads. These imbalances range in size from the switching of small loads, to the tripping of generation. There is a demarcation of imbalances into two types: those imbalances that are small and occur regularly, such as natural load variation and inaccurate dispatch; and those that are large and occur infrequently, such as contingent events. The grid is designed to manage contingent events to within the acceptable range to avoid blackout, i.e. from 48 to 52 Hz, and is therefore able to manage normal imbalances with ease. However, it is important to manage the normal frequency so that it lies within the normal range (49.8 to 50.2 Hz), so that the grid is in the best state to manage contingent events if one were to occur, and for efficient operation of the grid. If frequency were allowed a large range for normal operation, then it reduces the frequency space in which to manage contingent events, and indicates that the grid will manage contingent events ineffectively.

The value of frequency management services is hard to calculate in terms of monetary value, as it is difficult to model each of the relationships in the system, particularly contingent risk and the Instantaneous Reserve market. Therefore, value is primarily considered in terms of frequency quality and contingent event management. However, a monetary value is estimated based on a performance metric, i.e. the average power required to reach a minimum frequency of 48 Hz for a continent event, and a base estimate of the cost of load lost. The base cost is estimated by calculating how much load was lost on average for the 13 December 2011 [3] and 12 November 2013 [4] AUFLS events (650 MWh) and multiplying it with the Value of Lost Load (VoLL). The VoLL is taken as the average of the upper ($20,000 MWh) and lower ($10,000 MWh) range of the scarcity price range, to give a price of $15,000 MWh. The total cost of a single AUFLS event is estimated to be $9.8 million, since it is anticipated that these events occur once in every five years, the per annum cost is around $2 million.

The impacts of changes to frequency management are assessed by running power system simulations under different perturbations in system parameters, e.g. one case involves reducing inertia by 50%. Each of the different cases is seen in the header of Table 2. The simulation runs the Simulink model for eight separate days during 2014, which encompass summer, autumn, winter, and spring (4); and a weekday and weekend (2), to give a total of eight days (4 × 2 = 8).

VI. Discussion

Considering Table 2, it is apparent that with changes from 50% to 200% there is not a significant change in frequency quality that would be unsatisfactory for frequency management, assuming that the FKC controller is in regular use. A reduction in droop and increased governor time constant provides the largest degradation in frequency quality, reducing quality by 40%. A reduction in load-dampening constant reduces quality by 23%, and inertia has the least impact on frequency quality by reducing it by 11%.

TABLE II. Simulation Results of New Zeland Power System Frequency Quality

Cases	Frequency Quality Metrics					
	Standard Deviation, σ		*Bottom 5% Frequency* [a]		*Top 5% Frequency*	
	NI	*SI*	*NI*	*SI*	*NI*	*SI*
Base [b]	0.0374	0.0315	49.941	49.950	50.059	50.049
Inertia, 50%	0.0414	0.0359	49.935	49.943	50.065	50.056
Inertia, 200%	0.0349	0.0285	49.945	49.955	50.055	50.045
Droop, 50%	0.0527	0.0462	49.917	49.927	50.083	50.072
Droop, 200%	0.0284	0.0235	49.955	49.963	50.045	50.037
LDC, 50%	0.0460	0.0405	49.928	49.936	50.073	50.064
LDC, 200%	0.0297	0.0237	49.953	49.963	50.047	50.037
GTC, 50%	0.0292	0.0238	49.953	49.962	50.046	50.038
GTC, 200%	0.0517	0.0452	49.919	49.929	50.082	50.071
MFK, 0%	0.0376	0.0318	49.939	49.949	50.058	50.049
MFK, 50%	0.0375	0.0316	49.941	49.950	50.059	50.049
MFK, 200%	0.0372	0.0314	49.942	49.951	50.059	50.049

a. The bottom and top 5% Frequency refer to percentile values. The bottom 5% indicates the frequency where 5% of the time the frequency is below, and similarly for the top 5%.
b. The base case is where the historic values for inertia, droop, load-dampening constant, and governor time constant are the inputs for the simulations. The perturbations of 50 and 200% are from the base case, where, for example, if inertia is 50% then all inertia values in the model are multiplied by 0.5, while all other parameters remain the same as the base case.

Simulation For grid susceptibility, droop, inertia, and governor time constant have similar impacts, theoretically reducing the minimum frequency of 300 MW events from 48.45 Hz to 48.05 Hz. This will require greater procurement of Fast Instantaneous Reserve (FIR), and increase the chance of AUFLS shedding. However, it is difficult to estimate the actual increased cost of FIR and lost load.

Transpower have conducted a study, TASC Report 33 [2], on how much extra FIR is required to meet new wind generation investments, but no associated cost of that procurement is given. The marginal value of inertia is estimated from the cost of lost load as being $24 per MWs per annum, for droop $360 per MW/Hz per annum, for load-dampening constant $440,000 per MW/Hz per annum, and for governor time constant -$7660 per s per annum. These values do not highlight the necessity of having inertia, droop etc., as there is significant range over which these quantities have limited impact on frequency management performance. However, it is necessary to have inertia, droop, load-dampening constant, and governor time constant for a working power system, and facilitating the multi-billion dollar trading of energy.

TABLE III. RESULTS OF NEW ZELAND CONTINGENCY PERFORMANCE

Cases	**Contingency Event Performance Metrics**				
	Minimum Frequency for Event [a] **(HZ)**	***Event Size to Reach 48 Hz*** [b] **(MW)**	***% of times minimum frequency is below specified limit*** [c]		
			48 Hz	**47.5 Hz**	***47 Hz***
Base	48.445	397	48.78	18.01	0.00
Inertia, 50%	48.055	317	93.87	49.15	21.26
Inertia, 200%	48.863	508	14.43	0.00	0.00
Droop, 50%	48.041	315	94.29	50.12	21.84
Droop, 200%	48.798	513	12.84	0.00	0.00
LDC, 50%	48.169	337	88.05	38.42	15.05
LDC, 200%	48.814	520	11.84	0.00	0.00
GTC, 50%	48.786	508	14.52	0.00	0.00
GTC, 200%	48.055	317	93.78	49.12	21.30
MFK, 0%	48.444	397	48.78	18.10	0.14
MFK, 50%	48.445	397	48.78	18.03	0.13
MFK, 200%	48.445	397	48.79	18.00	0.13

a. The minimum event frequency is an average of minimum frequencies during a 300 MW event, if that event were to occur at any time. This value is calculated from the analytic model.

b. The event size to reach 48 Hz is the average required event size to achieve a minimum frequency of 48 Hz, if the event were to occur at any time. The value is calculated from the analytic model.

c For a 400 MW event, the % of time that event would cause the minimum frequency is below the specified frequency.

TABLE IV. ESTIMATED COST OF LOST LOAD

Cases	***Lost Load Cost over 5 years*** **($ Million)**
Base	9.8
Inertia, 50%	12.3
Inertia, 200%	7.7
Droop, 50%	12.4
Droop, 200%	7.6
LDC, 50%	11.5
LDC, 200%	7.5
GTC, 50%	7.7
GTC, 200%	12.3
MFK, 0%	9.8
MFK, 50%	9.8
MFK, 200%	9.8

ACKNOWLEDGMENT

The authors acknowledge the funding and support provided by the Ministry of Business Innovation and Employment, Transpower, the EEA and the University of Canterbury for the GREEN Grid project that has enabled this research to be carried out. We also acknowledge the help given in providing information to conduct this research, which has been very much appreciated, particularly to Conrad Edwards, Richard Sherry, and Charles Crystal of Transpower, and Rowan Sinton of Meridian Energy.

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